FLOW SENSOR APPLICATIONS IN A MAJOR OILFIELD AUTOMATION SYSTEM

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INTRODUCTION

The emergence of enhanced oil recovery (EOR) techniques in many of the older producing oilfields during the late 1960's and early 70's resulted in some dramatic increases in oil production, but it also increased the demand for accurate day to day operating information. Operators of formerly stable but minimal producing properties discovered that their antiquated well testing methods were unable to keep pace with the rapid changes which were taking place in stimulated well production. Worse, producing wells in need of remedial work and even wells completely off production often were going unnoticed because monitoring facilities and surveillance were inadequate. At the same time, management, faced with heavy EOR expenditures, was demanding quicker and more reliable field data to justify larger budgets.

During 1969, in anticipation of such a requirement, Getty Oil Company, which has since become part of Texaco, Inc., initiated a massive field automation program in it's Kern River Oilfield in California. The result was the SCAN system, or Sampling, Control and Alarm Network, which can be credited with supplying most of the field data and operating information necessary for the successful transformation of that 70 year old oilfield from a daily oil production of 45,000 barrels to a maximum of over 100,000 barrels per day. The system is still in full operation and has since been expanded to service 4600 wells instead of the 2200 wells connected at its inception. SCAN as an operating system has been well reported in prior literature (See ref.) so only a brief functional description is given here. This paper limits its scope to a portion of the system rarely touched upon by system analysts, the field-end hardware components which supply well data to the SCAN computer center. Especial attention is given to the individual well flow sensors, often referred to as flow/no-flow switches. These devices are worthy of special examination because they supply a stream of data which is of surprising importance to both engineering and operating groups. Their selection and application problems are also pretty typical of those encountered with other items of data producing hardware.

THE SCAN SYSTEM

Initially, the plan was to connect a number of automatic gauging panels which were widely distributed about the Kern River oilfield into a computer controlled network. The SCAN project quickly expanded in concept to include not only computer scheduling and control of individual well tests but to full time monitoring of all producing wells, steam injection wells and steam generator activity, and to creation of regular daily, weekly and monthly reports of these activities as well as special demand reports when needed. The final operational system included all these features plus numerous field malfunction alarms and warnings of abnormal performance at wells and steam generators.

As set in operation in 1969, and for some years thereafter, the entire SCAN system was controlled, monitored and reported by one dedicated Scientific Data Systems SIGMA II computer. The computer center was hard wire connected with 96 remote field well gauging stations or AWTs which, in turn, serviced over 2600 producing wells and 129 steam generators. The essential components of one AWT are shown in Figure 1. All control and information data was transmitted over a two pair binary network developed by CAE, Ltd., the same Canadian firm which devised the original SCAN software. The software design was based upon the concept that high speed scanning signals sent out continuously by the central computer could obtain all field data source information by periodic interrogation of the status of each meter, gauge or sensor which was equipped with a simple on/off switch. Similarly, periodic control signals sent out by the same computer could trigger remote relays and solenoids to operate well testing valves and pumps. It then followed that each item of the field-end data producing hardware should generate a binary status output, or in other words, an on/off switch contact. Surprisingly, that simple requirement was not so easily satisfied. Most of the available instrumentation at that time was designed for an analogue output. Consequently, many of the SCAN field-end components such as meters, pulsers, valve postion switches and temperature switches had to be modified or specially fabricated for the applications. When it came to selection of the well flow/no-flow sensors, a functional item which had already been decided upon, the SCAN designers anticipated no special problem. Not so!

FLOW SENSOR SELECTION

Any approach to full time metering of over 2600 wells was economically unfeasible. Getty Oil elected, instead, to gauge wells periodically at conventional well test batteries and to adopt a complementary system of flow sensors to perform two important intermediate tasks:

1. Detect and alarm wells off production to enable rapid response of well repair crews. The problem of uneven well flow, which is not unusual in low gravity oilfields, was so acute at Kern River that it was difficult to tell whether "heading" wells were actually off production for a number of days unless some monitor of continuous performance was provided.

2. Track variations in producing rate during the period between scheduled well tests. The flow rate of individual Kern River wells was subject to wide fluctuations as a result of the stimulus of steam injection to enhance oil recovery. It was hoped that flow sensor instrumentation could be used to yield timely information on significant changes in well performance between actual well gauges. In order to do so it was necessary that the sensors be able to ignore gas and steam and recognize oil and water alike.

During the process for selection of a flow sensor to alleviate these well monitoring problems, it quickly became evident that the reliability of the devices on test was seriously affected by the same fluid conditions which contributed to the uneven well flow, i.e., large fluctuations in viscosity, multiphase liquids, wide temperature ranges and sand flows. In order to function as required, the flow/no-flow sensors had to meet these criteria:

1. Tolerate intermittent slugs of water, gas or crude oil, with oil viscosities ranging to 30,000 Cp.

2. Operate at temperatures from 32 deg.F to 300 deg.F without essential change in flow response.

3. Resist abrasion from sand flows.

4. Yield the same flow response for either oil or water or any combination of the two fluids.

5. Provide a reliable switch output at nominal 5 B/D fluid rate within a range of 3 to 7 B/D.

6. Operate in a vertical position to avoid parallel flows of liquid and gas.

Using a field sited 2 inch piping manifold equipped with a fluid meter and a strip chart recorder it was possible to recreate to some degree each of these conditions except number 3 which required more time than was warranted. The various wells which were admitted to the test stand included examples of slug flow, high and low temperatures, all water to low cut viscous crude and varying combinations of all these conditions. Both horizontal and vertical flow were tested. The tests were purposely extended into the cold winter months with the temperatures into the low 3Ø's. The fallout of candidates was revealing:

All of the mechanical devices were eliminated due to their viscosity sensitivity. Most gave a totally different response to oil and water and exhibited marked changes in readout when oil temperature was varied. Paddle type sensors tended to stick in the heavy crude, small turbine types plugged. A spring loaded piston device showed some promise but required a change of spring constant for varying well rates and fluid compositions, could not differentiate between fluid and high gas flows and was still subject to sticking and potentially sensitive to sand abrasion. None of the mechanical instruments appeared to have acceptable repeatability.

Thermal flow sensors, that is, devices which utilize the thermal conductivity of fluids or heat transfer effects of flowing fluid to trigger a response to flow or no-flow, introduced new hope of meeting the SCAN requirement -- and a new and complex set of problems. The thermal flow sensing devices are actually rather sophisticated instruments which utilize hydraulic, thermodynamic and electronic principles all blended to achieve a design objective. Some of the instruments tested were masterpieces of electronics but seriously deficient in hydraulic technology; other units made ingenious use of heat flow to a detector probe but lacked stable and dependable electronic circuitry. One of the instruments offered was particularly interesting because it appeared to have all the component requirement plus a totally unrestricted flow passage and no fluid contact with the sensing elements. It utilized a heating coil, a reference coil and a sensing coil all wrapped about an in-line pipe nipple and hermetically sealed with a steel outer jacket. Wheatstone bridge electric circuitry to detect differentials between the sensing coil and the reference coil completed the package. The instrument had to be judged as unacceptable because its sensitivity was inhibited by excess thermal mass and the responses to oil and water were widely divergent. The flow sensing instrument which finally tested to meet the SCAN specification was a thermal type flow switch marketed by Fluid Components, Inc. (FCI) which made use of small heating, sensing and reference probes immersed in the flow stream and Wheatstone bridge balancing/switching circuitry amplified to operate a dry switch contact. The response time to fluid flow changes was rapid and the flow/no-flow switch point for either oil or water was acceptably close. The search for one more SCAN component was ended -- or so we thought.

The FCI flow sensor to which Getty committed itself in 1969 has since undergone little or no basic change. It consists of three probes which extend into the fluid stream. (See Fig.2) One of the probes is a 10 watt electric heating unit, the other two are resistance temperature detectors (RTD's) which are wired into a Wheatstone bridge electrical circuit. One of the RTD's is located directly above the heater probe and is selectively heated by a rising convection stream when the fluid is in a quiet, or no-flow state. The other RTD, located below and to one side of the heater, registers only the temperature of the unheated fluid. As a result, the two RTD's develop a maximum difference in resistance during a no-flow state, causing sufficient imbalance in the bridge circuitry to trigger a no-flow signal. During a flow condition, the horizontal flow stream carries off some of the convection heat and cools the heated RTD, reducing the temperature difference between the two RTD probes. The resulting bridge milliamp electrical output is an inverse but non-linear function of the fluid flow rate and can be amplified to trip a signal switch or operate a relay. (See Fig.3) The FCI sensor, as with most other flow sensors tested, was designed for horizontal flow. The vertical flow arrangement specified for the SCAN application required the addition of a small steel baffle to divert a portion of the fluid stream horizontally across the gap between the heater probe and the heated RTD, thus amplifying the difference between flow and no-flow temperatures. The size and shape of this baffle proved to be especially important because it helped to provide nearly equal switching points for both oil and water.

In addition to the fluid diversion baffle, one other departure from the standard flow sensor design was requested for the Kern River application: centralization of all flow sensor electronics packaging. Each flow sensor unit normally contained its own bridge circuitry, amplifier and contact switch within an attached condulet housing. For ease of calibration and maintenance this application preferred such components to be located in a single panel box at each automatic well testing battery (AWT). To meet this requirement, the circuitry was relocated onto plug-in circuit boards each containing the electronics for three channels or wells. The RTD and heater probes at the well manifold were simply wired to the panel which housed the circuit boards. A maximum of 36 wells could be accommodated at each AWT.

After receipt and installation of the first 1000 units of the flow switch it was discovered that the firm which FCI had licensed to manufacture the devices had deviated from specifications and slacked in quality control so far that many of the instruments were unusable. The baffle had been altered for ease of fabrication, the

RTDs were not properly matched and some of the electronic components were poorly selected and mounted. Facing a possible lawsuit, the manufacturer agreed to rebuild all units to meet Getty's specifications. Thereafter, FCI took on the production of the flow sensor in its own plant and pretty much eliminated further quality control problems. The same flow sensor is still in use at Kern River on 4600 wells despite numerous trials of competing instrumentation.

FLOW SENSOR APPLICATIONS IN THE SCAN SYSTEM

Why tolerate so many problems and so much expenditure of time to select just the right flow sensor? The concept of the SCAN application provides the answer. As mentioned earlier, the use of flow sensors was devised to complement the scheduled well tests by supplying two pieces of well performance data which were not otherwise available from the automatic well gauging system:

1. Documentation and alarms of wells off production.

2. Continuous monitoring of well flow status with recording of significant changes in performance.

Complete stoppage of flow from a well which is off production is normally reached only after fluid has dribbled from the lead line for several hours due to gas expansion, sucker rod agitation or even thermal expansion from daylight temperature. Conversely, a "heading well", one which produces intermittently, can enter the flow tank so erratically that occasional interrogation of the flow sensor may show mostly "no-flow" indications even though the well is producing its normal daily output. Instantaneous determination of a "well off production" status is at best misleading and more often totally in error. To avoid such erroneous flow indications, each flow sensor was calibrated to trigger its no-flow switch below a fluid flow rate of 5 to 7 barrels per day (0.013 FPS in 2 inch pipe) and revert to flow status above that rate of flow. Any well which consistently indicated a no-flow status when scanned by the computer at 7½ minute intervals was automatically alarmed and documented as off production for the day. Obviously, the accuracy of this wells off reporting system was heavily dependent upon the reliability of the flow sensors and their circuitry.

An even more critical demand on the flow sensors was their usage for computing well test gauges and to detect changes in well performance between well test gauges. Both applications required uniform and repeatable flow/no-flow switch points and near equal response to oil and water in order that all wells be monitored alike. The

SCAN computer was programmed to interrogate each flow sensor every 7½ minutes, or 192 times each day and totalize only those scans which indicated a flow status. These "flow" scans came to be referred to as "flow counts", or simply "counts". It was known that the majority of producing wells did not yield continuous flow counts either during test periods or during most full days of operation. It had also been observed earlier that the instantaneous gross producing rate of most heading wells was closely proportionate to the coincident flow indications. Based upon these approximations, software was designed to use flow counts accumulated by the computer first to compute 24 hour rates from short term well tests, then to estimate interim producing rates at individual wells:

To Compute the 24 Hour Flow Rate from a Short Term Well Test:

Onto the usual expansion calculation was appended a modifying factor which consisted of the ratio of flow scan percentages during the day of test to the flow scan percentages during the actual hours of test:

BPD = (Test Volume)(24/Test Hours) x (% Day Count / % Test Counts)
= T (24/H) ((Day Counts / 192) / (Test Counts / 8H))

Where: 192 = Maximum possible counts during 24 hour day

8H = Maximum counts during test period of H hours

BPD = T (Day Flow Counts) / (Test Flow Counts)

Note that the test hours cancel, leaving the expansion a simple ratio of flow counts during the day of test to flow counts during the well test. Thus, any fractional test period is automatically expanded to a full 24 hour day rate.

Example:		
	Test period	= 4 Hours
	Test volume (T)	= 20.1 Barrels
	Flow counts during day of test	= 172
	Flow counts during test period	= 30

BPD = 20.1 (172 / 30) = 115.2 or 115 barrels per day rate

The usual expansion based only on time would have produced a value of 121 barrels per day.

To Compute the Estimated Producing Rate Between Well Tests:

In order to monitor well producing rate and detect major changes in performance between scheduled well tests, a similar computation was devised to estimate interim gross producing rate based upon the last well test and succeeding flow counts from the flow/no-flow sensor.

Estimated Flow Rate On Any Day (n) Following Well Test Gauge:

BPD n = BPD Test (Flow Counts Day n / Flow Counts Test Day)

Example:	Test gauge gross rate	= 115 BPD
	Flow counts day of test	= 172
	Flow counts day 1	= 180
	Flow counts day 6	= 175

BPD 1 = 115 (180 / 172) = 120 barrels per day

BPD 6 = 115 (175 / 172) = 117 barrels per day

One of the many tasks demanded of the SCAN computer was to accumulate oil and water production by wells and totalize the information for a monthly field production report. Since it was virtually impossible to schedule physical gauge tests of all wells on the last day of the month, the technique described above was used to provide data wherever actual measured well gauges were unavailable. The result was a theoretical oil and water production report by wells which was included with a list of other well information on a monthly magnetic tape output as a source document for regulatory reports. With the technique established, it was also possible to produce a demand report of production to date by wells or well groups on any day of the month. Exhibit 1, attached, is an example of one such accumulation by well test batteries (AWTs). This ability to accumulate and report concurrent production of any selected group of wells became especially useful in monitoring the performance of multiple well steam stimulation areas or steam drive projects within the Kern River oilfield.

PROJECT PERFORMANCE

So much for planning, selection, installation and testing. Ultimately the SCAN hardware had to undergo the final test, performance appraisal. That turned out to be a never ending task. The AWTs were put on line one or two at a time and each carefully checked for mechanical and signal malfunctions. Since the project goal was 96

AWTs and each required from two days to a week or more for working approval, the six months originally allocated for startup was totally inadequate. The system, or some portion of it, was producing useful information within a month, but a year later bugs were still being discovered and eliminated. Both engineering and operating personnel gradually began to recognize that neither a task force approach nor wholesale replacement of suspect components was effective without continuous follow up maintenance. The SCAN project involved over 22 thousand widely scattered field components including the mechanical relays used to signal data. At some point within any new system of that magnitude it could be expected that almost daily examples of Murphy's Law might emerge. The trick was to sidestep malfunctions so that component failures or erroneous data did not become devastating. SCAN was designed to do just that by using such devices as maintaining the last prior gauge if an AWT reported suspect information. So even though both hardware and software problems were being debugged the Kern River oilfield was not thrown into chaos during the lengthy break-in period. And despite malfunctions, the SCAN system was put into effective use within a surprisingly short time after the computer was on line.

Again, the experience with flow sensor performance appraisal was typical to that of the other field end data producing components. After correction of the initial manufacturing and calibration defects, which has already been discussed, the sensors worked admirably but they produced information so different than that obtained by manual methods that their performance was seriously doubted. A considerable amount of effort was put into well observation and check calibration of flow sensors before confidence was established that the information they produced could be relied upon. This determination of flow sensor reliability was especially important to the automatic gauging operation. Among other concerns, the computer generated queuing schedule for well testing would not accept a well which the flow sensor indicated as off production but would schedule for test a well which was erroneously reported as producing.

The real flow sensor problems appeared much later when sand erosion began to take its toll on the deflecting baffle and probes and, more seriously, the 10 watt heater probe on many sensor heads became encrusted with carbonaceous scale. The erosion problem was encountered only infrequently at first but was potentially serious because a probe which was perforated by sand cutting could permit leakage of well fluid into the electronic flow sensor circuitry for an entire AWT. A damaged flow deflector baffle could alter the sensitivity of the sensor. The heater encrustation was usually caused by overheating of oil entrapped in the probe area during a time when the well was idle. This, too, could cause loss in sensitivity and a potential imbalance in the circuitry when the well was restored to production. Correction of these problems was relatively simple. Possible erosion was countered with abrasion resistant coatings and added barriers against leakage in the event of serious sand cutting. Heater encrustation could be reduced or eliminated by cutting off electric power to the heater probe while the well was idled. The big lesson, though, was the demonstrated need for a continuous maintenance program. Without periodic removal of probe heads for a physical inspection and recalibration of the electronic circuitry, progressive failures such as described above are hard to detect until the affected well demonstrated an obvious anomaly in production performance. Meanwhile, an unknown amount of misinformation about the well may have been documented needlessly.

The long range performance of the flow sensors has been exceptional. The majority of the sensors which were installed 19 years ago are still in service, including their electronic package which contains some outdated components. A program is currently in progress to modernize the original circuit boards but the probe heads will remain unchanged. Additional installations have been made since 1969 to bring the number of flow sensors in use to a present total of 4600. Present planning calls for each future well which is drilled at Kern River to be connected into the SCAN gauging system and to be equipped with a flow sensor.

Some alterations have been made in processing of the flow sensor data output. The Kern River field oil reservoirs have noticeably increased in temperature as the result of live steam injection during a field wide thermal recovery program. Since the heated oil now flows more uniformly, the abnormal heading condition which was described earlier has eased somewhat and ceases to be a problem in well gauging. This, combined with software changes related to a computer replacement, has deleted the use of flow counts in computing 24 hour producing rates. Well gauges are now calculated by the computer from a time expansion of short term tests. However, the well test is not accepted if the flow sensor reports less than 2/3 of the maximum flow counts during the test period or 2/3 for the day of the test. This change in data handling is fairly new and still under evaluation. Another change in flow sensor usage is an increase in flow/no-flow trigger point setting on some high volume wells to a 50 barrel per day rate. This allows detection of an abnormal decline in flow rate before the well ceases to produce and suggests a new function for flow sensor usage.

FLOW SENSOR MAINTENANCE

There are two principal points of maintenance for a SCAN system flow sensor: the probe head which contains one half of the bridge circuit and the electronic circuit board which includes the other half of the bridge and signal amplification to operate a flow/no-flow status switch. All of the flow sensor circuit boards are housed in a common panel at each AWT. Every "No-Flow" alarm for which the pumper can find no justification is referred to a field technician who has instrumentation to check for circuitry faults at the panel. Correction usually consists in readjustment of a potentiometer which controls the "flow/no-flow" trigger point. If a more serious problem is detected, the faulty circuit is replaced with a new plug-in circuit board. The piping manifold is also inspected for valve leaks which can yield a spurious flow/no-flow signal. The probe heads are usually removed for inspection at annual or longer intervals unless an abnormal probe condition is suspected. A program for removing and cleaning the probe heads every six months has recently been recommended. Field manpower requirement for flow sensor maintenance consists of 1 Automation Technician and 1 Repairman.

SUGGESTIONS FOR FLOW SENSOR APPLICATION IN OTHER OILFIELD ENVIRONMENTS

The recent Kern River usage of flow sensors settotrigger no-flow at 5Ø b/d suggests the possibility of extending the application of these instruments to monitor wells in oilfields with limited gauging facilities. Sensors are now available with dual trigger points which can indicate flow rate decline below, say 4Ø b/d as well as no-flow below 4-5 b/d. The 4Ø b/d point could signal the need for well testing, the no-flow alarm for a pump change or well repair. If a computer is involved, the well test could be self-scheduled. Chart recorders or a multiple scanning device could be used for a data recording center in lieu of the computer employed in the SCAN system. A strip chart recorder can be used periodically to examine and interpret the flow sensor output of wells with heading characteristics. Time delay panels are available to signal a "Well Off" alarm after any desired period of "no-flow" indications from the flow sensor. All manners of simple through sophisticated applications can be dreamed up for these long lived flow sensors. The ultimate objective, though, is quicker response to well problems and reduction of down time. Any scheme which accomplishes this is usually repaid in oil very quickly.

CRITERIA FOR SELECTION

A few words are offered on practical criteria for selection of flow/no-flow sensors. As indicated earlier, a multitude of designs and prices are available. A single phase of fluid (oil or water) can be sensed with rather simple instrumentation unless high repeatability is demanded. A paddle type sensor is satisfactory for a swimming pool heater shutoff but inadequate for an aircraft hydraulic system leak alarm. The usual oilfield fluid environment does not allow the luxuries of clean single phase fluid, a comfortable range of viscosity, and freedom from air and gas containment. Before selection and purchase of a flow sensor the physical fluid properties and flow conditions to be encountered in the application should be documented in a bid request along with the usage requirements. Any conditions peculiar to the application such as corrosiveness, slug flow, abnormal temperature ranges or excessive amounts of solids should also be noted. A hazardous environment may be a special consideration. Cost is not the primary objective.

Field testing is mandatory. If any modifications to the factory model have been required, both prototype and production models should be field tested. If an inexpensive mechanical device seems well suited to the application and tests out properly, fine. But keep in mind that failure is liable to occur sooner and the cost of field repair or replacement may quickly erode the saving over a more expensive thermal type sensor. Above all, after the flow sensor is selected, tested, installed and put on line, do not walk away and forget it as engineers sometimes do. Plan a maintenance program and set up diagnostics to prevent the flow sensors from producing misinformation instead of useful operating data. Then, after you convince yourself that the new information you are getting is correct, relax a little and enjoy the results - until the field foreman begins to object to the new set of well problems on the daily report.

REFERENCES

Shore, R.A.,: "The Kern River SCAN Automation System - Sample, Control and Alarm Network," Society of Petroleum Engineers of AIME, Dallas (1972)

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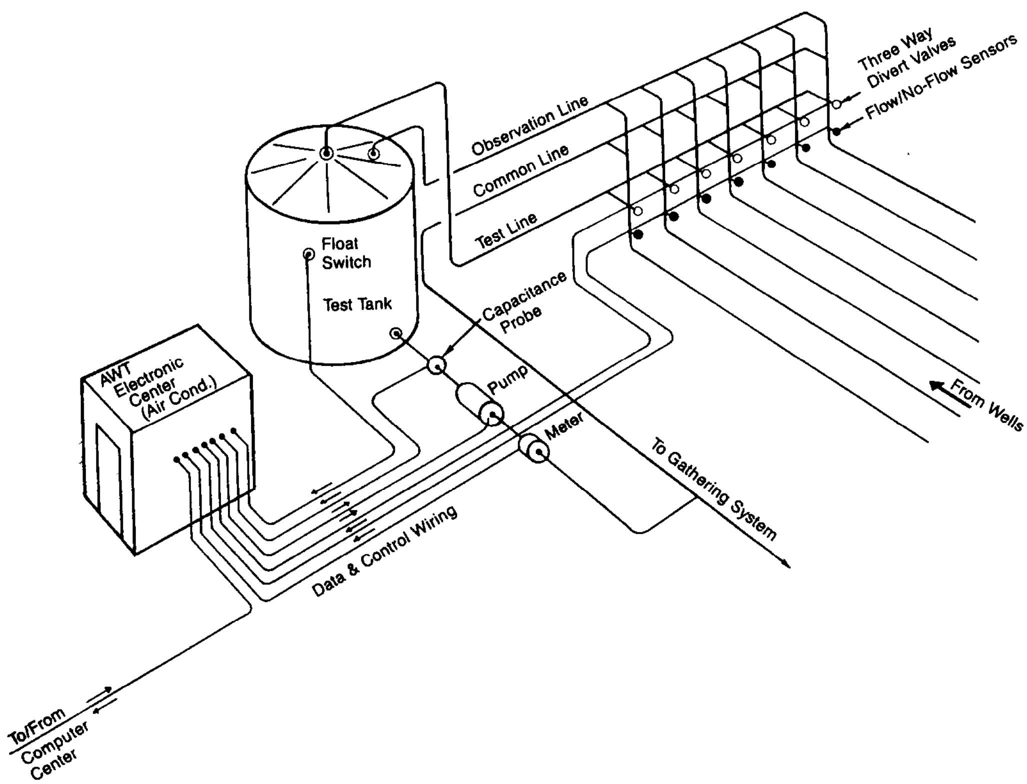

Figure 1 - Schematic diagram of automatic well test site (AWT)

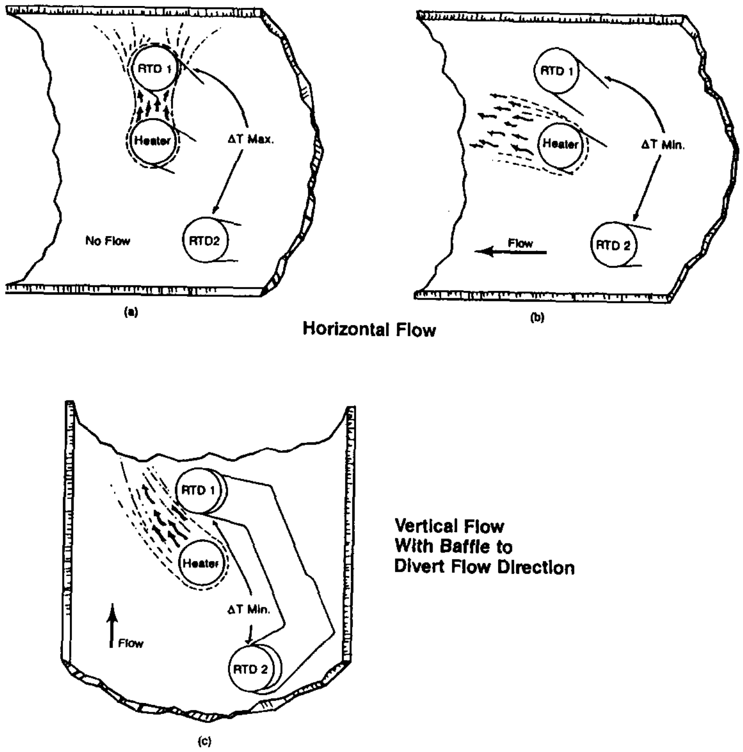

Figure 2 - Dispersion principle
of FCI sensor

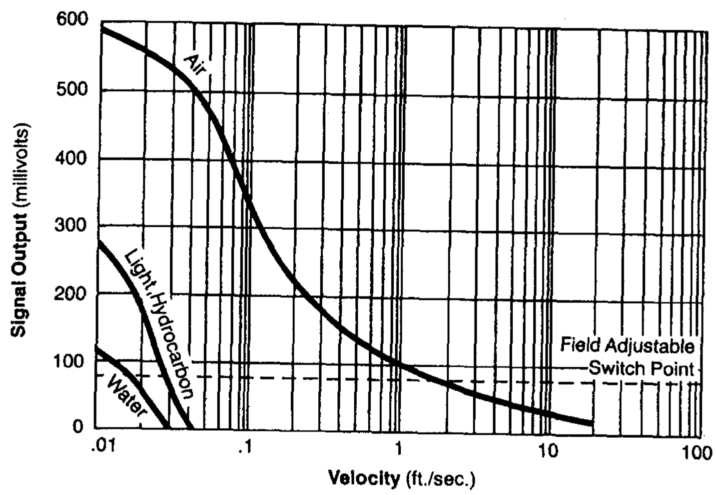

Figure 3 - Flow sensor output
vs flow rate